TECHNICAL REVIEW DOCUMENT
For
RENEWAL TO OPERATING PERMIT 95OPAD047

Colorado Interstate Gas Company – Watkins Compressor Station
Adams County
Source ID 0010036

Prepared by Jacqueline Joyce
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Revised January and February 2013

Reviewed by:

Operating Permit Supervisor:	Matt Burgett
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I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The current Operating Permit was issued on January 1, 2008. The expiration date for the permit was January 1, 2013. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted December 30, 2011, additional information submitted on December 5, 2012, comments on the draft permit and technical review document received on February 21, 2013, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251596446069. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating

permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

The facility is a natural gas compression facility as defined under Standard Industrial Classification 4922. Natural gas enters the Watkins facility at a pressure between 400 and 700 psig. Some of the gas is blended with air to achieve a customer specified Btu value prior to delivery to customers. The remaining natural gas is compressed up to a pressure of 920 psig. Eleven (11) internal combustion engines are used at this facility to drive compressors. In addition, a 560 gallon above ground gasoline storage tank, cold cleaner solvent degreasers and process heaters have been included in Section II of the operating permit as significant emission units.

The facility is located in a flat, suburban area approximately 3 miles due east of Aurora, CO. The Denver Metro Area is classified as attainment/maintenance for particulate matter less than 10 microns in diameter (PM_{10}) and carbon monoxide (CO). Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as nonattainment for ozone and is part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park, a Federal Class I designated area, is within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document for the previous renewal permit has been updated to reflect the potential to emit (PTE) of both criteria (all criteria) and HAP pollutants due to changes that may have occurred in emission factors and/or emission limitations since the previous renewal permit was issued. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	Potential to Emit (tons/yr)					
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC	HAPS
Engine E001	0.37	0.02	150.1	20.5	4.3	See Table on Page 17
Engine E002	0.37	0.02	150.1	20.5	4.3	
Engine E003	4.18	0.05	84.7	26.7	10.4	
Engine E004	4.18	0.05	84.7	26.7	10.4	
Engine E005	4.18	0.05	84.7	26.7	10.4	
Engine E006	4.18	0.05	84.7	26.7	10.4	
Engine E007	4.18	0.05	84.7	26.7	10.4	
Engine E008	4.18	0.05	84.7	26.7	10.4	
Engine E009	4.18	0.05	84.7	26.7	10.4	
Engine E010	4.18	0.05	84.7	26.7	10.4	
Engine E011	4.18	0.05	84.7	26.7	10.4	
Total	38.36	0.50	1,062.5	281.3	102.2	56.39

In the above table, the criteria pollutant PTE for the engines is based on either permitted emissions or the appropriate emission factors, design rate and 8760 hours per year of operation. Emissions from the gasoline storage tank, process heaters and the cold cleaner solvent degreasers were not included since criteria pollutant emissions are below APEN de minimis levels and the facility is a major stationary source for PSD and non-attainment area review without including them.

In the above table, the breakdown of HAP emissions by emission unit and individual HAP is provided on page 17 of this document. The HAP PTE is based on the Division's analysis. As indicated in the table footnotes on page 16, the HAP PTE was based on the highest emission factor in HAPCalc 3.0 (GRI field data, GRI literature and EPA) for each pollutant, design rate and 8,760 hrs/yr of operation. Emissions from the gasoline storage tank, process heaters, and the cold cleaner solvent vats were not included since HAP emissions are below the APEN de minimis levels and the facility is major for HAPs without including them.

Actual emissions are shown in the table below and according to the APENs submitted on November 24, 2010, emissions are based on 2009 data plus 25%.

Emission Unit	Actual Emissions (tons/yr)					
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC	HAPS
Engines E001 & E002	0.22	0.01	138.5	19.2	4.0	1.5
Engines E003 – E007	6.8	0.1	133.6	42.2	16.9	10.3
Engines E008 – E011	9.5	0.1	187.5	59.2	23.7	14.3
Total	16.52	0.21	459.6	120.6	44.6	26.1

National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories

As indicated in the above table summarizing potential to emit, the facility is a major source for HAPS and may be subject to NESHAPs for specific source categories (hereafter, referred to as "MACT requirements"). The applicability of various MACT requirements were discussed to some extent in the technical review document prepared to support the second renewal of this permit (issued January 1, 2008). That discussion has been updated to reflect changes to the various MACT standards and the promulgation of any new standards that may apply.

Natural Gas Transmission and Storage (NGTS) Facility MACT (40 CFR Part 63 Subpart HHH)

The provisions in 40 CFR Part 63 Subpart HHH apply to glycol dehydrators located at major sources of HAPs. Since there is no glycol dehydrator at this facility, the requirements in Subpart HHH do not apply.

Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ)

The reciprocating internal combustion engine (RICE) MACT was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. Under this rulemaking only RICE that were > 500 hp and located at major sources of HAPS were subject to the requirements. Subsequent revisions were made to the RICE MACT to address new engines ≤ 500 hp located at major sources and new engines of all sizes at area sources (final rule published January 18, 2008), existing compression ignition engines ≤ 500 hp at major sources and all sizes at area sources (final rule published March 3, 2010) and existing spark ignition engines ≤ 500 hp at major sources and all sizes at area sources (final rule published August 20, 2010). Revisions were made to the RICE MACT on January 30, 2013. The January 30, 2013 revisions did not change the applicability requirements but did change the specific requirements for some engines (e.g. engines greater than 500 hp located at area sources of HAPs).

As discussed in the technical review document for the second renewal permit (issued January 1, 2008), Engines E001 thru E011 are existing (commenced construction prior to December 19, 2002) 2-stroke and 4-stroke lean burn engines > 500 hp and are not required to meet the requirements in 40 CFR Part 63 Subparts A and ZZZZ, including the initial notification requirements (see § 63.6590(b)(3)(i) and (ii)).

There is one 500-hp natural gas-fired emergency generator included in the insignificant activity list. According to the technical review document for the second renewal permit (issued January 1, 2008), the emergency generator was noted in an April 24, 2004 inspection report and so it was included in the insignificant activity list in the second renewal. In their Title V renewal application, Colorado Interstate Gas (CIG) indicated that the emergency generator was actually rated at 570 hp. The applicability of MACT Subpart ZZZZ is based on the site-rated hp of an engine. An engine with a site rating greater than 500 hp located at a major source of HAP emissions is existing if construction or reconstruction commenced prior to December 19, 2002. An engine with a site rating less than or equal to 500 brake hp located at a major source of HAP emissions is existing if construction or reconstruction commenced prior to June 12, 2006.

CIG submitted information on December 5, 2012 indicating that the engine's maximum rating is 593 hp at sea level and based on the manufacturer's recommended de-rate procedures (2% for every 1000 feet over 3000 feet) the engine is site-rated at 563 hp (based on a site elevation of 5540 feet). The December 5, 2012 information also indicated that the engine had commenced operation in 1978. Therefore, since this engine is site-rated at 563 hp and was installed in 1978, it is not required to meet the requirements in Subpart A and ZZZZ, including the initial notification requirements, as provided for in § 63.6590(b)(3)(iii).

Organic Liquid Distribution (Non-Gasoline) MACT (40 CFR Part 63 Subpart EEEE)

The applicability of this MACT to the Watkins Compressor Station is as discussed in the technical review document prepared for the second renewal permit (issued January 1, 2008). Under 40 CFR Part 63 Subpart EEE §§ 63.2334(c)(2), organic liquid distribution operations do not include activities and equipment at NGTS facilities; therefore, the organic liquid distribution MACT requirements do not apply.

Boiler MACT for Major Sources (40 CFR Part 63 Subpart DDDDD)

EPA promulgated National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters on March 21, 2011. These requirements apply to boilers and process heaters that are located at major sources of HAPs and as such these requirements apply. There is no de minimis level specified in the requirements and there is fuel-burning equipment identified in the insignificant activity list that is potentially subject to these requirements. Since all of the fuel-burning equipment at the facility only burns natural gas, only work practice standards (i.e., boiler tune-ups) apply. As a result the boilers and process heaters that are subject to Boiler MACT requirements will be removed from the insignificant activity list and included in Section II of the permit.

EPA proposed revisions to the Boiler MACT on December 23, 2011 and final revisions to the Boiler MACT were published in the Federal Register on January 31, 2013. The January 31, 2013 final rules have no affect on the applicability of the Boiler MACT to the boilers and process heaters at this facility.

New Source Performance Standards (NSPS)

EPA has promulgated NSPS requirements for new source categories since the issuance of the second renewal permit for this facility. NSPS requirements generally only apply to new or modified equipment and the Division is not aware of any modifications to existing equipment or additions of new equipment that would render equipment at this facility subject to NSPS requirements. However, because the recently promulgated NSPS requirements address equipment that may not be subject to APEN reporting or minor source construction permit requirements, the applicability of some of the newly promulgated requirements are being addressed here.

NSPS Subpart JJJJ – Stationary Spark Ignition Engines

NSPS Subpart JJJJ applies to stationary spark ignition engines that commenced construction, reconstruction or modification after June 12, 2006 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. The compressor engines commenced operation in 1974 - 1978 and there is no indication that these units have been modified since that time. As discussed under the RICE MACT, the emergency generator commenced construction (on-site construction) prior to June 12, 2006. Therefore, the requirements in NSPS Subpart JJJJ do not apply to any of the engines at this facility.

NSPS Subpart IIII – Stationary Compression Ignition Engines

NSPS Subpart IIII applies to stationary compression ignition engines that commenced construction, reconstruction or modification after July 11, 2005 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. There are no compression ignition engines located at the Watkins Compressor Station, therefore, the requirements in NSPS Subpart IIII do not apply.

NSPS Subpart OOOO – Crude Oil and Natural Gas Production, Transmission and Distribution

The provisions in NSPS Subpart OOOO apply to several affected facilities at crude oil and natural gas production, transmission and distribution facilities that commenced construction, modification or reconstruction after August 23, 2011. The affected facilities under NSPS OOOO include gas wells, compressors (centrifugal and reciprocating), pneumatic controllers, storage vessels, equipment leaks associated with process units (i.e., equipment used to extract natural gas liquids from field gas) and sweetening units located at onshore natural gas processing plants. In the first case, the facility commenced operation in the 1970s and it is not apparent that any equipment at the facility was constructed, reconstructed or modified after August 23, 2011; however, the Division has reviewed the potential applicability with respect to the individual affected facilities.

Gas wells are an affected facility under Subpart OOOO but there is no gas wells associated with this facility.

The pneumatic controllers and compressors are only affected facilities if they are located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. Since this facility is a part of the natural gas transmission and storage segment, any compressors or pneumatic controllers are not affected facilities, regardless of when they were constructed, reconstructed or modified.

Equipment associated with process units and sweetening units located at onshore natural gas processing plants are affected facilities under Subpart OOOO. There are no sweetening units at this facility. There are no natural gas processing plants associated with this facility.

Any storage vessels with VOC emissions greater than or equal to 6 tons/yr of VOC that commenced construction, reconstruction or modification after August 23, 2011 would be an affected facility and would be subject to the requirements in Subpart OOOO. There are a number of storage vessels included in the insignificant activity list in the permit, however, the facility commenced operation in the 1970s and the Division is not aware that any tanks have been constructed, reconstructed or modified after August 23, 2011.

Therefore they don't meet the applicability date (i.e. commenced construction, reconstruction or modification after August 23, 2011) and they are not affected facilities.

In summary, there are no Subpart OOOO affected facilities located at the Watkins Compressor Station so the requirements in Subpart OOOO do not apply.

Colorado Regulation No. 7, Sections XII and XVIII – Requirements for Oil and Gas Operations in the 8-hour Ozone Control Area

The applicability of the requirements in Section XII was discussed in the technical review document for the August 30, 2006 revised permit beginning on page 8. The requirements in Section XII were revised somewhat since that revised permit was issued and the requirements in Section XVIII were added and so a discussion of these requirements is being included.

- Applicability and definitions (Sections XII.A and XII.B)

- Requirements for condensate collection, storing and handling (Section XII.C, D, E and F)

  As noted in the technical review document for the August 30, 2006 revised permit and in Section XII.A.1, these requirements apply to exploration and production operations, compressor stations or drip stations located upstream of a natural gas-processing plant. The Watkins facility transmits pipeline quality natural gas (i.e. gas that has been processed) to end users; therefore, the facility is located downstream of a natural gas processing plant and these provisions do not apply to the condensate tanks at this facility.

- Requirements for gas processing plants (Section XII.G)

  As noted in the technical review document for the August 30, 2006 revised permit, the Watkins facility is not a natural gas processing plant. There is no equipment at the facility that is used to extract natural gas liquids. Therefore, these provisions do not apply to the Watkins facility.

- Glycol Dehydrators (Section XII.H)

  There are no glycol dehydrators at the Watkins facility; therefore, these requirements do not apply.

The requirements in Section XVIII were adopted in December 2008 and apply to natural gas-actuated pneumatic controllers associated with natural gas operations in the 8-hour ozone control area or any ozone nonattainment or attainment maintenance area. These requirements specifically apply to pneumatic controllers located at or upstream of a natural gas processing plant. Note that Section XVIII specifically states that upstream activities include oil and gas exploration and production operations, natural gas compressor stations and/or natural gas drip stations. As previously stated, this facility is

located downstream of a natural gas processing plant, therefore, these requirements do not apply.

Colorado Regulation No. 7, Section XVI - Requirements for Engines in the 8-Hour Ozone Control Area and Section XVII – Statewide Requirements for Oil and Gas Operations

The requirements in Section XVI were adopted in March 2004 and apply to the 8-hour ozone control area. The requirements in Section XVII were adopted in December 2006 and apply statewide. The requirements in Section XVI apply to natural gas fired engines. The requirements in Section XVII include requirements for condensate tanks, glycol dehydrators and natural gas fired engines.

Condensate tank and glycol dehydrator requirements

Although actual uncontrolled emissions from condensate tanks are below the applicability levels in Section XVII (20 tons/yr), the Division considers that these requirements were intended to apply to condensate tanks located at facilities either located upstream or at a natural gas processing plant (i.e. would not apply to glycol dehydrators or condensate tanks in the natural gas transmission and storage category). This facility transmits pipeline quality natural gas and is within the natural gas transmission and storage category. As a result, these requirements do not apply. In addition, this facility has no glycol dehydrators.

Engine requirements

The requirements in Regulation No. 7, Section XVI apply to engines located in the 8-hour ozone control area and sets control requirements for engines greater than 500 hp. This facility is located in the 8-hour ozone control area and these engines are all greater than 500 hp. The provisions in Section XVI.C.4 specify that lean burn engines operating in the 8-hour ozone control area prior to June 1, 2004 are exempt from the control requirements in XVI if the owner or operator demonstrates that the cost of retrofit control technology will exceed $5,000 per ton. Such demonstrations were to be submitted prior to May 1, 2005. The source submitted a demonstration indicating that the cost of retrofit controls would exceed $5,000 per ton on April 29, 2005 and in an October 12, 2005 letter, the Division agreed that the exemption applied to engines E001 through E004. Note that in the August 30, 2006 revised Title V permit the description of engines E001 and E002 was revised to indicate that the engines were 4-cycle lean burn engines. Prior to the August 30, 2006 Title V permit, engines E001 and E002 were identified as rich burn engines.

Reg 7 was revised in 2008 to include control requirements for natural-gas fired engines state-wide. These requirements are found in Section XVII.E and apply to both new and existing engines. The requirements for existing engines apply to engines that were constructed or modified before February 1, 2009 greater than 500 hp. The requirements are similar to the requirements for engines over 500 hp located in the 8-hour ozone control area and provides the same exemption for lean burn engines (if

source demonstrates retrofit control costs are greater than $5,000 per ton the engine is exempt). Therefore, the requirements for existing engines in Reg 7, Section XVII.E.3 do not apply. The requirements for new engines depend on the date the engine commenced construction or relocation and the size of the engine. Engines E001 through E011 are not new and therefore, the requirements for new engines in Section VIII.E.2 do not apply.

Compliance Assurance Monitoring (CAM) Requirements

In the technical review document for the first renewal of this permit (issued July 1, 2003), the Division noted the following with respect to CAM.

> Although the current operating permit indicates that several of the engines are controlled (i.e. clean burn), a clean burn engine design or operating mode is not considered a control device as defined in 40 CFR Part 64 §64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since passive control measures that act to prevent the pollutants from forming, such as the use of combustion or other process design features or characteristics are not considered control devices. In addition, although the gasoline storage tank is identified as being controlled (submerged fill pipe), potential uncontrolled emissions are unlikely to exceed the major source levels. Therefore, since none of the significant emission units at this facility are equipped with control devices and have potential uncontrolled emissions over major source levels, the Compliance Assurance Monitoring (CAM) requirements do not apply to any emission units at this facility.

The applicability of CAM to the equipment at this facility has not changed since the first renewal (issued July 1, 2003). CAM does not apply to any emission unit at this facility.

Greenhouse Gas Emissions

The potential-to-emit of greenhouse gas (GHG) emissions from this facility is greater than 100,000 TPY CO_2e. Future modifications greater than 75,000 tons per year CO_2e may be subject to regulation (Regulation No. 3, Part A, I.B.44).

Repealed APEN Exemptions

Since the second Title V renewal permit was processed (issued January 1, 2008) the APEN exemptions for engines – limited size and hours (Reg 3, Part A, Section II.D.1.sss) and emergency generators – limited size and hours (Reg 3, Part A, Section II.D.1.ttt) was repealed. Although the specific APEN exemptions for engines and emergency generators have been repealed, these emission units are still exempt from APEN reporting requirements if actual, uncontrolled emissions are below the APEN de minimis level.

CIG submitted information on December 5, 2012 indicating that actual emissions from the emergency generator were below the APEN de minimis level (1 ton/yr for NO_X and VOC and 2 tons/yr for other criteria pollutants).

III. Discussion of Modifications Made

Source Requested Modifications

CIG's requested modifications were addressed as follows:

December 30, 2011 Renewal Application

Appendix A – Insignificant Activity List (Smalling Regeneration Heater)

CIG indicated that the Smalling regeneration heater is actually 8.0 MMBtu/hr, rather than 7.0 MMBtu/hr as indicated in the insignificant activity list for the current permit. The insignificant activity list indicates a level of hours of operation, below which the heater would be APEN exempt and CIG requested that this level be revised to reflect the higher heat input rate and the lower APEN de minimis level since the area is now non-attainment. Since the heater is subject to the Boiler MACT under the catch-all provisions in Colorado Regulation No. 3, Part C, Section II.E, the heater can no longer be considered an insignificant activity, so the heater will be removed from the insignificant activity list and included in Section II of the permit. Note that since the Division has not adopted the Boiler MACT requirements the heater is still exempt from the APEN reporting requirements provided actual, uncontrolled emissions are below the APEN de minimis level. The Division will note the level at which the Smalling regeneration heater would exceed the APEN de minimis level in the permit.

Cold Cleaner Solvent Degreaser

CIG indicated that there are in fact two cold cleaner solvent degreasers at the facility and requested that the permit be revised to reflect this. However, in their comments on the draft permit and technical review document received on February 20, 2013, the source indicated that there was only one cold cleaner solvent degreaser. Therefore, no changes were made to the permit.

Section II, Condition 1.1 – Engines E001 and E002

CIG requested that the language in Condition 1.1 be revised to remove the language indicating that annual emissions are required for purposes of APEN reporting and annual fees and to revise the language to require that emissions be calculated monthly and used in a rolling twelve month total.

No changes were made to the permit based on the source's request. It has been the Division's practice in Title V permits to require only annual recording of throughput (or fuel consumption) and emission calculations for emission units that are not subject to

annual emission limitations (i.e. tons/yr limitations). The purpose of requiring the annual calculations are to verify whether or not a revised APEN is required (annual fees are based on emissions reported on the APEN), hence the permit indicates that the purpose for conducting these emission calculations is for APEN reporting and payment of fees. The Division does not consider this language to be inconsistent with the APEN reporting requirements and/or the requirement to pay fees. Therefore the language will not be revised.

Section II, Condition 1.4 – Engines E001 and E002

CIG requested that the requirement to continuously monitor the O_2 concentration be removed. CIG's justification for removal of this requirement is that in the 5 year period over which the O_2 concentration had been monitored, the level has never fallen below 2%. In their application, CIG indicated that when the monitors were installed the engines were setup to automatically shutdown when the exhaust oxygen content hit 3% or below and that a shutdown due to that event has never occurred. The Division included the requirement to continuously monitoring the O_2 concentration in the exhaust because the engines had originally been identified as rich burn engines but by re-classifying them as lean burn engines CIG avoided the control requirements in Colorado Regulation No. 7, Section XVI and in the RICE MACT. While the engines never operated below 3% O_2 in the exhaust during the period that the O_2 monitors have been installed, if the O_2 monitors were removed there would be no data indicating that these engines were continuing to operate as lean burn engines (O_2 concentration at or above 2%), nor would there be an automatic shutdown of the engines at 3% O_2. Therefore, the requirement to continuously monitor the O_2 concentration will remain in the permit.

Section II, Condition 2.4 – Engines E003 through E011

CIG requested that the requirement to determine the Btu content of the gas semi-annually be removed. CIG considers that with 10 years of data on the Btu content of the gas is sufficient empirical data on the Btu content and that an average of the 10 years of semi-annual sampling data should be used as the Btu content in the emission calculations. The Division believes that determining the Btu content of the natural gas is still necessary and the requirement to determine the Btu content semi-annually will remain in the permit. It should be noted that in lieu of sampling Condition 2.4 allows CIG to average the gas composition of the natural gas using the in-line gas chromatograph over the semi-annual period and calculate the Btu content.

Insignificant Activity List

CIG submitted a comprehensive list of fuel burning equipment and storage tanks that should be included in the insignificant activity list. The Division included this list, except that process heaters that are subject to the Boiler MACT were not included in the insignificant activity list but were included in Section II of the permit.

CIG also indicated that the hp rating of the emergency generator should be updated to reflect the original design rate of 570 hp. The Division updated the emergency generator information in the insignificant activity list based on the information submitted on December 5, 2012.

Company Name Change

In the renewal application, CIG indicated that the company name had changed to Colorado Interstate Gas, LLC. In addition, CIG requested that the address be changed under "issued to". The changes were made as requested.

Permit Contact

In the renewal application CIG requested that the permit contact be changed. Since the renewal application was submitted the permit contact has changed again and the permit was revised to include the appropriate contact.

In their comments on the draft permit and technical review document submitted on February 20, 2013, CIG requested that the primary responsible official be changed. This change was made as requested.

Other Modifications

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments to the Watkins Compressor Station Renewal Operating Permit. These changes are as follows:

Page Following Cover Page

- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

Section I – General Activities and Summary

- Revised the description in Condition 1.1 to include the process heaters as equipment included in Section II and to indicate that Rocky Mountain National Park (a federal class I area) is within 100 km of the facility.

- Condition 1.4 was revised to remove Section IV, Condition 3.d as a state-only requirement, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

- The AOS for temporary engine replacement was included in Condition 2.

  Note that the permanent AOS cannot be provided since the facility is a major stationary source for purposes of PSD and non-attainment area NSR review and none of the engines with emission limitations have permitted emissions below the significance level. The temporary AOS specifies 270 days for temporary engine replacement, since the permanent AOS cannot be provided. It is expected that if a permanent engine replacement is required that either a modified Title V permit or a construction permit can be issued within that time frame.

- The following changes were made to the table in Condition 6.1:

  - Combined the emission unit no. and facility id columns.
  - The second column was labeled AIRS point number as that is more appropriate.
  - The process heaters no longer qualify as insignificant activities and have been included in the table.

Section II.1 – Engines E001 and E002

- Removed the sentence in Condition 1.4 indicating that the monitoring device shall be installed within 60 days of revised permit issuance [August 30, 2006] since the date has passed and the monitor is installed and has been in use for several years.

Section II.2 – Engines E003 – E011

- The portable monitoring language in Condition 2.5 was revised to the latest version.

Section II.3 – Gasoline Storage Tank

- Added a note indicating that this tank was exempt from the APEN reporting and construction permit requirements.

Section II.4 – Cold Cleaner Solvent Degreaser

- Added a note indicating the degreaser is exempt from the APEN reporting and construction permit requirements.

"New" Section II.5 – Boilers and Process Heaters

Since the facility is a major source for HAP emissions the equipment at this facility is subject to the Boiler MACT requirements. There are no boilers and process heaters included in Section II of the current permit but as indicated previously, there is no de minimis level for affected facilities under the Boiler MACT. Therefore, any boilers or process heaters identified in the insignificant activity list would be subject to the Boiler MACT requirements.

In their December 30, 2011 renewal application, CIG submitted a detailed list of fuel burning equipment to be included in the insignificant activity list. CIG identified the fuel burning equipment that would be subject to the requirements in 40 CFR Part 63 Subpart DDDDD in their December 5, 2012 submittal and the list includes the Parker and Bryan boilers (rated at 4.3 and 3.6 MMBtu/hr, respectively) and the Struthers and Smalling regeneration heaters (rated at 4 and 8 MMBtu/hr, respectively). CIG noted in the December 5, 2012 submittal that although the Parker and Bryan units as designated as boilers, they do not meet the definition of boiler in 40 CFR Part 63 Subpart DDDDD § 63.7575, because they do not have "the primary purpose of recovering thermal energy in the form of steam or water". However, the Parker and Bryan boilers do meet the definition of process heaters in § 63.7575.

In their December 5, 2012 information submittal, CIG indicated the purpose of the fuel burning equipment identified in the December 30, 2011 renewal application. Most of the heaters in the list are used for comfort heat. The definition of process heater in § 63.7575 excludes units used for comfort or space heat, so those heaters are not affected sources under 40 CFR Part 63 Subpart DDDDD. CIG also identified three water heaters which in accordance with § 63.7491(d) are not subject to the requirements in Subpart DDDDD (capacity of the water heaters is less than 120 gallons, each). Therefore only the four process heaters are subject to the requirements in 40 CFR Part 63 Subpart DDDDD.

Since the four heaters (Parker and Bryan boilers and Smalling and Struthers regeneration heaters) are subject to the requirements in 40 CFR Part 63 Subpart DDDDD, under the catch-all provisions in Reg 3, Part C, Section II.E, they can no longer be considered insignificant activities because they are subject to federal NESHAP requirements. Therefore, these four heaters have been removed from the insignificant activity list and included in "new" Section II.5 of the permit.

The process heaters are subject to the following applicable requirements:

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)

- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)

Based on engineering judgment, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to these units. In addition, since these units are not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to these units. Process modifications and startup may apply to these units, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Therefore, the 30% opacity requirement has not been included in the operating permit.

- Particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu, where FI is the fuel input in MMBtu/hr (Reg 1, Section III.A.1.b).

- Boiler MACT requirements (40 CFR Part 63 Subpart DDDDD), which include the following:

    - Energy assessment

    - Boiler tune-ups

Since these units are not subject to APEN reporting or minor source construction permit requirements, the permit will not include any requirements for calculating emissions.

Section III – Permit Shield

- The following changes were made to the table in Section III.1 (permit shield for specific non-applicable requirements):

    - Revised the shield for the requirements in Regulation No. 1, Section III to indicate that the shield only applies to engines E001 through E011, to more specifically identify the Reg 1 requirements and to revise the justification.

    - Removed the permit shield for the requirements in Reg 3, Part D, Sections XIII and XIV, since the facility is within 100 km of a federal class I area.

Section IV – General Conditions

- Revised the version date.

- The paragraph in Condition 3.d indicating that the requirements are state-only has been removed, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

- Condition 29 (VOC) was revised primarily to add the provisions in Reg 7, Section III.C as paragraph e although other minor language and format changes were made.

Appendices

- The following changes were made to the insignificant activity list in Appendix A:

  - Grouped activities by the insignificant activity categories and noted those categories for which records should be available to verify insignificant activity status.
  - Updated the list to incorporate those additions noted in the December 30, 2011 renewal application.
  - Removed the Parker and Bryan Boilers and the Smalling and Struthers Regeneration Heaters and included them in Section II of the permit since these units are subject to requirements in 40 CFR Part 63 Subpart DDDDD.

- The tables in Appendices B and C were revised to include the fuel burning equipment subject to the requirements in 40 CFR Part 63 Subpart DDDDD. In addition, the name change to "Colorado Interstate Gas Company, LLC" was reflected in Appendices B and C.

- Changed the Division contact for reports in Appendix D.

- Cleared the table in Appendix F.

HAPS from GRI-HAPCalc 3.0 (Highest Possible)

Unit	HAP Emissions (tons/yr)										
	acetaldehyde	acrolein	Benezene	toluene	ethyl benzene	xylene	formaldehyde	2,2,4 trimethylpentane	n-hexane	methanol	**total**
E001	1.96E-01	8.57E-02	4.98E-02	3.11E-01	3.70E-03	1.47E-02	1.47	1.52E-02	3.73E-02	5.15E-02	2.24
E002	1.96E-01	8.57E-02	4.98E-02	3.11E-01	3.70E-03	1.47E-02	1.47	1.52E-02	3.73E-02	5.15E-02	2.24
E003	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E004	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E005	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E006	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E007	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E008	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E009	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E010	3.66E-01	4.37E-01	7.92E-02	2.34E-02	4.30E-03	1.07E-02	4.57	1.77E-02	7.09E-02	1.88E-01	5.77
E011	3.66E-01	4.37E-01	7.92E-02	2.34E-02	0.00	1.07E-02	4.57	0.02	7.09E-02	1.88E-01	5.77
Total	3.69	4.11	0.81	0.83	0.05	0.13	44.07	0.19	0.71	1.80	56.39

Engine emissions are based on the highest emission factor from HAPCalc 3.0 - (GRI field data, GRI literature data and/or EPA) for each pollutant.